Montana – Dakotas
Regional Transmission Study

WEST SIDE STUDIES

UPPER GREAT PLAINS REGION
Transmission Planning

JULY 2002

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EXECUTIVE SUMMARY

The Montana Dakotas Regional Transmission Study -- West Side (Montana Transmission Study) investigates potential transmission line solutions geared toward strengthening and improving transmission infrastructure in the state of Montana to deliver new resources to load centers in the west. The results of this Study are intended to provide insight into the challenges and requirements of developing and exporting Montana's diverse energy resources in the form of electric power.

The Upper Great Plains Region of Western Area Power Administration was directed to conduct a planning study of transmission expansion options pursuant to language in House Report 107-148, the Conference Report for the Supplemental Appropriation Act, 2001, Pub. L. 107-20. Public input was solicited and used as a basis for scope development. This report documents the west side studies. The scope of the Montana Transmission Study includes the analysis of five new generation options in different locations within the state of Montana. Several transmission line alternatives were studied with the focus on exporting power to Spokane, Salt Lake City, Denver, or Lethbridge, Canada. Each of the five generation options was analyzed separately with various transmission line alternatives developed with input from the public process. Additional facility improvements required in order to integrate the new generation and transmission lines into the existing system were made when necessary.

Project 1 modeled a 1000 MW coal-fired power plant near Colstrip with four transmission line alternatives at 230 kV and 500 kV voltage levels.

Project 2 simulated a 1000 MW generation facility located at Great Falls and three 500 kV transmission line alternatives.

The Project 3 model was composed of a 500 MW thermal generating station near Billings with three transmission options consisting of 230 kV and 500 kV voltage levels.

Project 4 evaluated the effect of 600 MW of new wind generation near Fort Peck and two 500 kV transmission options.

Project 5 modeled six individual 100 MW wind farms located at Blackfeet, Fort Peck, Great Falls, Billings, Livingston, and Yellowtail. No transmission lines were added to facilitate power exportation of Project 5.

System modeling, power flow, and stability analyses were performed with the "Positive Sequence Load Flow" (PSLF) version 11.2 software package by General Electric International, Inc. The Study utilized the 2002 Light Summer Operating Case and the 2002 Heavy Summer Operating Case system models provided by the Western Electricity Coordinating Council (WECC). These two models were used as the base cases for development of all Project models.

Analyses of the Projects were made based on system performance with system intact (Category A) and single line outage (Category B) conditions in power flow and dynamic stability studies. Results were evaluated in terms of NERC/WECC Reliability Criteria. A comparison was made between each Project model and the corresponding base case model to determine the impact of the Project on the interconnected transmission system. System losses and estimated Project costs were also analyzed. Multiple contingency outage analysis was not within the scope of this study, but is required in order to show compliance to the NERC/WECC multiple contingency (Category C) criteria. It would be appropriate to incorporate the multiple contingency analysis into a refined study which first addresses any system intact, stability, or single outage issues.

Results of power loss analysis indicate a correlation of real power losses between similar line routes regardless of the amount of new generation added. For example, adding new transmission from Montana to Denver results in a reduction in system losses. The most beneficial transmission line options in terms of power losses were those routed directly to the schedule areas of Denver, Salt Lake City, or Spokane. Decreases in total real power losses were observed in Projects 2 and 3 for lines and schedules to Salt Lake City and in Projects 3 and 4 for lines and schedules to Denver.

System intact and single contingency (Category A and Category B) power flow analysis demonstrated heavy loading of the 161 kV system adjacent to the Amps transfer constraint in Idaho. Loading of the 161 kV, 100 MVA Jefferson phase-shifting transformer reached 119% in the system intact analysis of Project 2 Line 2 with power scheduled to Salt Lake City.

Additional violations occurred during contingency conditions. Substations located at the load-end of the new transmission lines typically experienced overloads and undervoltages during nearby contingencies for all projects considered. The largest effects were observed on the 230 kV facilities at Bell Substation near Spokane and the Daniels Park Substation near Denver. This suggests that additional outlet transmission must be considered at these load centers to fully integrate the project into the system without any criteria violations. Results from separate expansion studies currently being conducted by the Bonneville Power Administration may indicate methods to alleviate facility loading at Bell Substation, and could be incorporated in future studies.

The transmission line alternatives proposed for each project proved to be critical power flow paths for the export of new Project generation. Overloads and non-converged cases were the frequent result of outages on sections of the new transmission lines because unit tripping was not assumed on the new units. Although unit tripping is prevalent on the existing western grid, the focus of this Study was to identify the necessary transmission system improvements, as opposed to evaluating the effectiveness of using remedial action schemes for the new units. In order to support the magnitudes of new generation used in this Study and meet Category B reliability criteria, additional line sections may be required from the new generator locations to other points in the system to help reallocate power flow, maintain transient stability, and prevent overloads of the existing system during contingencies.

The most significant benefits brought about by the new transmission lines were the offloading of power flow from nearby systems. Specifically, the number and severity of certain Category B rating violations were reduced when power flow was able to utilize the new transmission lines after a nearby contingency. However, violations created or worsened by the Projects near the load centers suggest that additional outlet transmission may be needed and should be the basis for a future study effort.

Detailed study results that were used to generate this report are available to be downloaded from Western's website at *http://www.wapa.gov/ugp*. Please contact the Upper Great Plains region for further information.

The results of this Study should not be used to replace the need for specific System Impact Studies or the OASIS request process for a new interconnection. Examination of the results indicates the presence of several principal issues that must be addressed regardless of the location of future generation or high-capacity transmission facilities.

1. INTRODUCTION AND STUDY SCOPE

1.1 Background

Western Area Power Administration was directed to conduct a study pursuant to the following language in House Report 107-148, the Conference Report for the Supplemental Appropriation Act, 2001, Pub. L. 107-20: "Non-reimbursable funding of $250,000 is provided to conduct a planning study of transmission expansion options and projected costs in Western's Upper Great Plains Region. Existing Western transmission capacity is insufficient to support the development of known energy resources that could support new electric generation capacity in the Upper Great Plains Region. The directed study will require assumptions as to future generation locations. Western is directed to solicit suggestions from interested parties for the sites that should be studied as potential locations for new generation and to consult with such parties before conducting the study. Western is directed to produce an objective evaluation of options that may be used by all interested parties."

Additionally, House Report 107-258, the Conference Report for the Energy and Water Development Appropriations Act 2002, Public Law 107-66, states, "Within the amount appropriated, not less than $200,000 shall be provided for the Western Area Power Administration to conduct a technical analysis of the costs and feasibility of transmission expansion methods and technologies. These funds shall be non-reimbursable. Western shall publish a study by July 31, 2002 that contains a recommendation of the most cost-effective methods and technologies to enhance electricity transmission from lignite and wind energy. "

In order to fulfill the requirements of the above-referenced Congressional directive, Western conducted a public workshop on October 19, 2001, and also accepted written comments. Based on the directive and input from interested parties, a detailed study scope was formulated. By using funds appropriated in Fiscal Year 2001, and some of Fiscal Year 2002, Western was able to expand the study scope.

The Montana Transmission Study – West Side was conducted under contract by Peak Power Engineering, Inc. A companion report prepared by ABB Inc. summarizes results from the Montana Dakotas Regional Study – East Side (UGPR Transmission Study). A second companion report entitled Transmission Enhancement Technology Report was prepared by SSR Engineers, Inc and contains a review of the methods and technologies to enhance electricity transmission from lignite and wind energy that Western has considered through various research projects.

This report documents results of the Montana Transmission Study of the West System. The objective of this study was to identify transmission reinforcements or other power system upgrades necessary to accommodate one of several possible new 1000 MW generation developments in Montana. This study should be considered a high-level feasibility study and does not include sufficient detail to receive project approval at the

Regional, State, or local levels; nor does this study attempt to determine if a project is economically justifiable. Five different generation sites along with various transmission alternatives to deliver the generation to three different load centers were identified in the public process.

1.2 Scope

The Study investigates the following generation and transmission combinations based on comments received at the public forum and using engineering judgment. Appropriate generation output is scheduled based on the transmission alternatives. Details of how each of the scope items affect study methodology is described in the subsequent discussion of each Project. System modeling was performed with the “Positive Sequence Load Flow” (PSLF) version 11.2 software package by General Electric International, Inc.

1.2.1 Project 1

1000 MW coal-fired generation interconnected at the existing Colstrip 500 kV bus, with generator output scheduled to Spokane, Denver, and Salt Lake City.

Transmission Alternatives:

- Add a 230 kV line from Colstrip to Fort Peck; upgrade the existing Fort Peck to Great Falls line from 161 kV to 230 kV
- Add a 500 kV line from Colstrip to Spokane (Bell Substation)
- Add a 500 kV line from Colstrip to Denver (Daniels Park Substation)
- Add a 230 kV line from Colstrip to Fort Peck; upgrade the existing Fort Peck to Great Falls line from 161 kV to 230 kV; add a 500 kV line: Lethbridge-Great Falls-Townsend-Dillon-Salt Lake City

1.2.2 Project 2

1000 MW gas-fired generation at Great Falls, Montana, with generator output scheduled to Spokane, Denver, and Salt Lake City

Transmission Alternatives:

- Add 500 kV line from Great Falls to Spokane
- Add 500 kV line from Great Falls to Denver
- Add 500 kV line: Lethbridge-Great Falls-Townsend-Dillon-Salt Lake City

1.2.3 Project 3

500 MW thermal plant at Billings with generator output scheduled to Spokane, Denver, and Salt Lake City

Transmission Alternatives:

- Add 500 kV line from Billings to Spokane, add 230 kV from Shelby to Lethbridge
- Add 500 kV line from Billings to Denver
- Add 500 kV line from Billings to Salt Lake City

1.2.4 Project 4

600 MW of wind centered at Fort Peck with generator output scheduled to Spokane, Denver, and Salt Lake City

Transmission Alternatives:

- Add 500 kV line from Great Falls to Spokane; upgrade Fort Peck to Great Falls from 161 kV to 230 kV; add 230 kV from Shelby to Lethbridge
- Add 500 kV line from Fort Peck to Denver

1.2.5 Project 5

Add 100 MW of wind generation at six sites: Blackfeet, Great Falls, Billings, Yellowtail, Fort Peck, and Livingston with generation output scheduled to Spokane, Denver, and Salt Lake City. No new transmission added.

2. PROCEDURE AND CRITERIA

The Montana Transmission Study analyzed the following technical categories. The Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Council (NERC) planning criteria were used to evaluate the impact of the Projects and transmission alternatives on the interconnected transmission system. Table 1 provides a summary of the merged NERC/WECC Reliability Criteria.

Table 1 -- Merged NERC/WECC Reliability Criteria (1)

Performance Category	Bus Voltages[1]	Branch Flows	Transient Voltage and Frequency Dips
- Category A - All Lines In Service	Normal Range: (1± 0.05) pu Stable solution at ≥ 105% of MW rating (load or path)	≤ Normal Ratings	No transient voltage and frequency dips
- Category B - Single Contingency	Emergency Range: (1± 0.10) pu ΔV ≤ 5% relative to pre-disturbance Stable solution at ≥ 105% of MW rating (load or path)	≤ Normal or Emergency Ratings[2]	≤25% at load buses ≤30% at non-load buses > 20% voltage, ≤ 20 cycles at load buses > 59.6 Hz, < 6 cycles at load buses
- Category C -	Emergency Range: (1± 0.10) pu ΔV ≤ 10% relative to pre-	≤ Emergency Ratings	≤30% at any bus > 20% voltage, ≤ 40 cycles at load buses

[1] Per unit voltages based on following transmission kV bases: 115, 161, 230, 345, and 540.
[2] The applicable rating is determined by the duration of the contingency. Flows must be within normal ratings for contingencies which last more that 30 minutes.

Multiple Contingency	disturbance Stable solution at ≥ 102.5% MW rating (load or path)		> 59.0 Hz, < 6 cycles at load buses

2.1 Power Flow

Power flow analysis was performed on each of the projects and transmission scenarios and compared using accepted criteria. Results from the power flow analysis document transformer and transmission overloads found as a result of adding the Project when compared to the existing model. Additionally, voltage levels throughout the transmission system (115 kV and above) were monitored to determine what effect the Project had on nominal operating voltages.

Two types of conditions were studied in the power flow analysis. Category A refers to the operating condition where all transmission facilities are in service. Category A may also be referred to as "N minus zero" (N-0) analysis. Category B, also known as N minus one (N-1), indicates that any one section of the transmission system is out of service and therefore not carrying power. During each line outage or contingency, power flow control devices such as tap changers, static VAR controllers and phase shifting taps were held fixed at their pre-contingency values.

2.1.1 Power Flow Study Criteria - Normal Overloads

Normal overloads are those that exceed 100 percent of normal ratings. The NERC/WECC Planning Standards require the loading of all transmission system facilities to be within their normal seasonal ratings.

2.1.2 Power Flow Study Criteria - Emergency Overloads

Emergency overloads are those that exceed 100 percent of emergency ratings. The emergency overloads refer to overloads that occur during single component contingencies (NERC Category B). The NERC/WECC Planning Standards require the loading of all transmission system facilities to be within their emergency seasonal ratings for any outage in NERC Category B.

2.2 Transient Stability

Transient or dynamic stability analyzes the short-term effect of disturbances, such as a contingency, on the power system. Simulations were run to determine the Project's affect on system stability.

2.2.1 Dynamic Stability Study Criteria

According to the Merged NERC/WECC Disturbance-Performance Table of Allowable Effects on Other Systems, after a Category B disturbance, the transmission system performance should meet the following criteria:

- Transient voltage dip should not be greater than 25 percent at load buses or 30 percent at non-load buses at any time.

- The duration of a transient voltage dip greater than 20 percent should not exceed 20 cycles at load buses.
- The minimum transient frequency should not fall below 59.6 Hz for 6 cycles or more at load buses.

Similarly, after a Category C disturbance, the transmission system performance should meet the following criteria:

- Transient voltage dip should not be greater than 30 percent at any bus at any time.
- The duration of a transient voltage dip greater than 20 percent should not exceed 40 cycles at load buses.
- The minimum transient frequency should not fall below 59.0 Hz for 6 cycles or more at load buses.

Note that the majority of the transient stability studies investigated Category A and Category B contingencies; however, one Category C outage was performed in dynamic analysis to study the system's transient response to the simultaneous loss of both Project 1 generators.

2.2.2 Dynamic Stability Study Procedure

Fault locations were chosen in each Project based on the location of the generating station and anticipated problem spots. In general, engineering judgment was used to determine faults that have historically been severe or were thought to create the greatest swings of the Project generators.

Two types of faults were analyzed: three-phase with normal clearing time and single-line-to-ground with delayed clearing time. Wherever possible, the fault was applied to an existing bus in the system so that a comparison could be made of pre- and post-Project dynamic responses. Transient voltage and frequency dips that did not meet the NERC/WECC criteria were noted, and those that were affected by the addition of the Project are discussed in this Study.

For fault locations on new buses added to the system by the Project, the effect of the Project is measured by inspecting the post-Project dynamic responses to the disturbance at existing and new buses, and their relationship to the Study criteria.

It is important to note that the all of the buses which were analyzed for this Study operate at transmission voltage levels; therefore possible violations on lower voltage load buses may not have been identified. Frequency dips were, however, analyzed in this Study even though the NERC/WECC frequency criteria apply only to load buses. Consequently, frequency dips observed are reported for the sake of thoroughness, and may or may not be an indication of frequency violations on load buses.

2.2.3 Colstrip Acceleration Trend Relay (ATR) Modeling

During stability analysis it was determined that for certain fault locations the Colstrip ATR model did not function correctly based on historical data of previous studies completed by other entities and accounts of actual ATR operations. In order to study the Project effects on dynamic stability as thoroughly as possible with the modeling software used for the Study, manual simulation of the Colstrip ATR was executed for fault scenarios in which it was determined that the model was misrepresenting the relay. Please refer to Section 3.4.4 for a more detailed discussion of the effect on Study results due to the manual simulation of the ATR.

Manual simulation of the Colstrip ATR was applied by the following sequence of events. Times in cycles are relative to moment that the fault was applied to the faulted bus.

- At 10 cycles, trip Colstrip Unit 1 operating at 330 MW and associated plant load of 26 MW.
- At 11 cycles, trip Colstrip Unit 3 operating at 710 MW and associated plant load of 60 MW.
- At 11 cycles, trip Miles City DC tie supplying 195 MW to the western grid.
- At 12 cycles, trip Montana Unit 1 operating at 39 MW.
- At 18.5 cycles, transfer 80% of Colstrip Unit 1 plant load to the Colstrip 115 kV bus.
- At 18.5 cycles, transfer 80% of Colstrip Unit 3 plant load to the Colstrip 230 kV bus.
- At 19 cycles, bring online a 10 MVAR reactor at Rosebud 230 kV.
- At 19 cycles, bring online a 22 MVAR reactor at Custer 230 kV.

When appropriate, additional events were executed as follows:

- Series capacitors on the existing 500 kV lines located at Broadview and at Garrison were bypassed for the duration of faults on Garrison 500 kV.
- Existing reactors at Colstrip 230 kV (48 MVAR) and Broadview 230 kV (96 MVAR) were brought online five seconds after fault clearing if voltage on the adjacent Colstrip or Broadview 500 kV bus remained at or above 1.10 pu.

The manual implementation of the Colstrip ATR was applied to the pre- and post-Project faults to ensure an accurate comparison of Project impacts could be made, and in some cases is a more restrictive action than might be necessary with the new Project in service.

2.3 System Losses

The real and reactive power losses were compared for each model with the Project and new schedule to a load center against the corresponding base case model. Results of this examination are presented in the form of the net change in system losses in each of the designated model areas.

2.4 Cost Analysis

All cost estimates for these projects were prepared using data from the 2000 Conceptual and Budget Cost Estimating Guide provided by Western. Project costs were escalated to 2002 using the economic escalation rates provided in that document.

The cost estimates for this Study are very preliminary. Site visits and design refinements could result in significant changes. These costs do not include planning, lands and rights, environmental, surveys, geologic investigations, designs and specifications, or construction supervision.

Project 1 through 3 cost estimates begin at the low side of the GSU transformers and include equipment up through connections to the various transmission buses as detailed in the individual Project reports.

Project 4 and 5 cost estimates begin at the low side of the Wind Generation Substation transformers and include up through connections to the various transmission buses as detailed in the individual Project reports.

Cost data was not available for Static VAR Controllers (SVC's) which were applied to the model cases. Instead, the estimated costs of appropriately sized reactor or capacitor banks were applied where required.

3. STUDY ASSUMPTIONS

3.1 System Models

The WECC 2002 Heavy and Light Summer Operating Cases provide the basis for the Project models. The condition of the system as given by the WECC models is compared to the condition after the Project has been added. The Project's net effect can then be gauged.

3.1.1 2002 Heavy Summer Operating Case

The 2002 Heavy Summer model provides a basis for the Projects when studying new transmission paths and power flows to load centers south of the state of Montana. As described in the associated material accompanying the WECC models, this model represents anticipated heavy flows for summer 2002 to load centers in California (1). Tie line flows from Montana to the Northwest area are 1119 MW. Flows south to the PACE area are 239 MW.

3.1.2 2002 Light Summer Operating Case

The 2002 Light Summer Operating Case represents light summer conditions with heavy flows to loads in the Northwest area (3). This case was used as a basis for Project transmission lines and power flows to the Northwest area. Tie line flows from Montana to the Northwest area are 1784 MW. Flows south to PACE are 22 MW.

3.1.3 Base Case Violations

Computer models provided by the WECC contain the best available data for studying the effect of new transmission and generation and may include some inaccuracies that would produce results that vary from actual operation. Some criteria violations were present in the base case models used to conduct this Study. The existence of these violations does not imply the compliance or non-compliance of any existing system to NERC/WECC Transmission Standards. The effect of the Project on pre-existing criteria violations in the model is reported if a 5% or greater change in the violation value is observed, or if the violation is brought within criteria.

3.1.4 Operating Procedures

The specific operating procedures of facilities mentioned in this report are not known. While they do not affect the accuracy of power flow results, operating procedures may impact the interpretation of results. In most cases, existing Remedial Action Schemes (RAS) were not accounted for in dynamic analysis. New RAS designs were not developed to correct instability issues caused by the Project. In some cases, however, if instability could be isolated to a single generator unit, that unit was manually tripped in order to determine other impacts of the Project. The instances where units were manually tripped are noted on a case by case basis.

3.2 Project Generating Stations

Each Project's generating station was modeled using suitable constants for a generic unit of similar type. This study was not intended to be a study of generation options. Appropriate models were used for the excitation system, governor/prime mover, and power system stabilizer when applicable. For the purpose of this system model, no station service loads were added at any of the generating facilities.

3.2.1 Project 1 – 1000 MW Coal-fired Generation

The generating station for Project 1 was modeled as two units with a net power output of 500 MW each. The models used for each of the two generators are as follows:

- Generator: represented by uniform inductance ratios rotor modeling to match WECC type F (shaft speed effects are neglected).

- Excitation System: IEEE type 1 excitation system model. Represents system with DC exciters and continuously acting voltage regulators, such as amplidyne-based excitation systems.
- Prime Mover: IEEE steam turbine/governor model with deadband and nonlinear valve gain added.
- Power System Stabilizer: WECC power system stabilizer.

3.2.2 Project 2 – 1000 MW Gas-fired Generation

The Project 2 generating station was modeled after a gas turbine with typical excitation, generator and power system stabilizer constants. Three separate 333 MW generators were modeled in order to achieve the desired 1000 MW output. Each unit was modeled after the following:

- Generator: solid rotor generator represented by equal mutual inductance modeling.
- Excitation System: IEEE type ST4b excitation system model.
- Prime Mover: single shaft gas turbine model.
- Power System Stabilizer: IEEE type PSS2A dual input power system stabilizer.

3.2.3 Project 3 – 500 MW Thermal Plant

The generating station for Project 3 is modeled on the same basis as Project 1, but with only one generator with a net power output of 500 MW.

3.2.4 Project 4 – 600 MW Wind Farm

The wind turbines of Project 4 were modeled as induction machines. The induction machine was chosen due to the widespread use of this type of wind turbine. Four 25 MW induction machines were used to form a 100 MW wind farm. Six of these wind farms were installed in the vicinity of the Project location in order to achieve the desired 600 MW power output.

For the sake of modeling efficiency, the wind turbines were treated differently in the steady state analysis versus the dynamic analysis. In the steady state model, a synchronous generator was modeled to provide appropriate reactive power support at the wind farm bus. In reality, separate shunt capacitors or integrated voltage regulation would be required for proper functioning of induction-type wind turbines. Steady state modeling is not affected by this assumption.

In contrast, dynamic analysis modeled the wind turbines as induction machines to demonstrate the response of an induction generator to system disturbances. The software model used in the dynamic analysis accounts for this disconnect between the steady state and dynamic models. Rotor slip and reactive power consumption of the induction machine are calculated based on the steady state power output. The model also initializes a shunt capacitor at the machine terminals to account for the difference in reactive power between the two models (5).

A second assumption was made in the size of the generators. The wind turbines were approximated in groups of 25 MW, even though actual induction-type wind turbines average in the 1.0 MW range. This approximation does not affect power flow analysis. The machine constants of each 25 MW induction machine have been selected to approximate the dynamic response expected from a collection of smaller machines.

3.2.5 Project 5 – Six 100 MW Wind Farms

The generating units for Project 5 were modeled in a similar fashion as Project 4. Four 25 MW machines were used to form each of the six 100 MW wind farms. The wind farms were installed at each of the Project's locations.

3.3 Project Transmission Lines

For all the Projects in this Study, transmission line paths of different lengths were added to the system model to allow for power scheduling requirements. In most cases, new 230 kV or 500 kV transmission line paths were installed. The only exception is the 161 kV line from Fort Peck to Great Falls which was upgraded to 230 kV for Project 1 and to 500 kV for Project 4. For Project 5, line sections of 10 to 15 miles were installed at appropriate voltage levels to tap into existing buses at each of the six wind farm locations.

3.3.1 Transmission Line Construction

Added transmission lines or line upgrades for this Study were either at the 230 kV or 500 kV level and were assumed to be steel lattice towers. These voltages were considered due to the high power flow requirements of the new generators.

For both voltages, “Pheasant” was selected as the conductor to be used. “Pheasant” conductor is 1,272 kcmil ACSR with 54/19 stranding, and has a current carrying capability of 1,187 A. For the transmission towers, typical lattice structures were selected of sufficient size and strength to accommodate the assumed conductor. Three bundled conductors per phase were modeled for the 500 kV lines, and a single conductor per phase was modeled for the 230 kV lines.

With the construction details mentioned above, the transmission lines have a capacity of 1,700 MVA and 380 MVA for 500 kV and 230 kV, respectively. The line constants were calculated and applied to each of the new line sections in the model.

3.3.2 Line Routing Considerations

Transmission line routing was selected using topographical information and existing line routing. The topographical information was used to avoid traversing major obstructions such as lakes and reservoirs. Existing line routes were paralleled when feasible. Section lengths were limited to no more than 300 miles between facilities.

After the transmission line routing was selected, a routing and conductor sag margin of 10 % was added to the line section length. This total length was used in conjunction with the calculated transmission line constants to determine the overall line section parameters for the system model.

The selection of system tie locations for the Project Lines was made based on considerations such as the number and capacity of existing line sections joining at that location, and the existing and anticipated power flows in and out of the bus. When a connection between the new line and the existing system was deemed appropriate, a new system bus and/or transformer was added to the model and tied to the existing bus in the model. New buses were not created in locations where facilities of the appropriate voltage already existed in the model.

The physical configuration of the existing substations was not considered; however, in terms of system modeling, the assumptions made for system ties do not affect the accuracy or validity of the power flow or stability analysis results.

3.4 Notes on Study Results

Certain considerations have been given to the analysis of data produced by this Study.

3.4.1 Operating Voltage for 500 kV Systems

Actual operating voltages of the 500 kV transmission system in the Montana and Northwest areas are at 1.08 pu, or 540 kV. New 500 kV transmission facilities under study were also modeled at the 1.08 pu voltage level. Discussion concerning voltage violations on the 500 kV system are relative to the nominal operating voltage of 1.08 pu as opposed to the base voltage of 1.00 pu.

3.4.2 Implications of Study Criteria

The results and conclusions reported in this document focus on the effect of new generation and transmission configurations on the existing western transmission grid. It is outside of the scope of this study to evaluate the *existing* system in any capacity. Throughout this document, discussion on specific criteria violations is done with the sole purpose of illustrating the impact of the Projects.

Although new loading values of the existing system are useful information for an Impact Study, this Study focuses only on violations caused or worsened by the Projects. Because of the sizes of generation being studied and the “big picture” approach, an analysis of the violations will provide useful results for judging the feasibility of a new line and schedule combination. Study results are intended to pave the way for more detailed analysis of the most attractive Projects. Revisions and refinement of the project scenarios will be required before further analysis can be performed, but are not appropriate for this Study.

3.4.3 Non-converging Outage Cases

During contingency (Category B) analysis, a programmed automatic contingency processor steps through each single-section outage successively, calculating new power flow conditions for the entire model. Notable changes to system operating conditions due to each separate contingency are then output to a data file. For some contingency cases, the model does not readily calculate new power flow values. This is known as a non-converged contingency. Non-convergence means that the system model could not re-calculate an accurate power flow within a reasonable number of iterations.

Although it is sometimes possible to manually simulate the non-converged outage and arrive at a solved model, it is not practical to revisit each one. The reason for divergence in many of these contingency cases is that the surrounding system cannot support the power flow during that contingency. The effect on specific lines and transformers can usually be inferred by comparing the impact of similar adjacent outages that did converge.

3.4.4 Colstrip ATR

It is important to note that the Colstrip ATR is a unique and complicated device, and does not operate in the same sequence of events for all disturbances that it detects. Time delays to trip are also variable. Therefore, manual simulation cannot be expected to be completely accurate for all fault scenarios.

What is lost by the manual simulation approach is the effect that the Project may have on the Colstrip ATR itself and more importantly, on the existing units at Colstrip. For example, the addition of new 500 kV lines that create alternate power flow paths for generation at Colstrip will decrease the tendency of these units to “swing” in relation to the synchronicity of the entire system, resulting in improved stability. By manually simulating unit trips, the likely advantage of a new line is effectively ignored, and the transient response displays little improvement over the base case.

Bearing the disadvantages in mind, manual simulation does provide a consistently stable “base” dynamic response upon which the effect of the Project can be judged in terms of transient violations. It would be beneficial to future project development to incorporate a functionally accurate ATR model in order to obtain more realistic transient response data in this area.

3.5 Complete Study Data

Modeling output and detailed results that were used to generate this report are available by request from Western. Please contact the Upper Great Plains region for further information.

4. COMPARISON OF PROJECTS

While separately, each Project emphasizes the benefits and detriments of a specific configuration, some key assessments may be made by comparing all of the Projects. Table 2 summarizes the Study results from a system intact and stability standpoint. Transmission line alternatives marked as viable meet criteria for Category A and stability analyses, and provides a basis for further project development and refinement. Detailed analyses of the results are contained in the individual Project reports.

Table 2 - Viability Summary

Project	Line Code: Description	Schedule	Comments	Viable Project?
Project 1 1000 MW Coal-fired near Colstrip	L1: 230 kV Hiline upgrade	Spokane, Salt Lake City	230 kV Hiline upgrade and existing system insufficient for magnitude of generator output.	No
	L2: 500 kV to Spokane	Spokane	Slight overvoltages can be corrected by adjusting transformer taps.	**Yes**
	L3: 500 kV to Denver	Denver	Meets Criteria.	**Yes**
		Salt Lake City	Overloads: 161 kV Jefferson Phase transformer; Bonanza-Mona 345 kV (known constraints)	No
	L4: 500 kV Lethbridge to Salt Lake City	Salt Lake City	3% to 4% reduction in voltage on 500 kV buses: Broadview, Garrison and Bell.	No
		Lethbridge	Heavy loading on existing B.C. to Alberta transfer.	No
Project 2 1000 MW Gas near Great Falls	**L1: 500 kV to Spokane**	Spokane	Slight overvoltages can be corrected by adjusting transformer taps.	**Yes**
	L2: 500 kV to Denver	Denver	Instability at Fort Peck hydro Unit 1	No
		Salt Lake City	Overloads: 161 kV Jefferson Phase transformer; Bonanza-Mona 345 kV (known constraints)	No
	L3: 500 kV Lethbridge to Salt Lake City	Salt Lake City	Slight overvoltages can likely be corrected by adjusting transformer tap.	**Yes**
		Lethbridge	Alberta Voltage collapse during contingency.	No
Project 3 500 MW Coal-fired near Billings	**L1: 500 kV to Spokane; 230 kV Shelby to Lethbridge**	Spokane	One slight overvoltage. Correct by adjusting transformer tap.	**Yes**
		Salt Lake City	Line 1 is not adequate for this schedule.	No
		Lethbridge	Dependence on existing B.C.-Alberta transfer. Too many changes to Alberta system.	No
	L2: 500 kV to Denver	Denver	Meets Criteria.	**Yes**
		Salt Lake City	Overload: Bonanza-Mona 345 kV (known constraint)	No
	L3: 500 kV to Salt Lake City	Salt Lake City	One slight overvoltage. Correct by adjusting transformer tap.	**Yes**
Project 4 600 MW Wind near Fort Peck	**L1: 500 kV to Spokane; 230 kV Shelby to Lethbridge**	Spokane	Additional VAR support may be needed at Colstrip	**Yes**
		Salt Lake City	Overloads: 161 kV Jefferson Phase transformer; Bonanza-Mona 345 kV (known constraints)	No
		Lethbridge	Dependence on existing B.C.-Alberta transfer. Too many changes to Alberta system.	No
	L2: 500 kV to Denver	Denver	Review rating of Bonanza-Mona 345 kV line.	**Yes**
		Salt Lake City	Overloads: 161 kV Jefferson Phase transformer; Bonanza-Mona 345 kV (known constraints)	No
Project 5 100 MW Wind at Six Sites	No New Transmission Lines	Spokane	Instability at Fort Peck hydro Unit 1	No
		Denver	Instability at Fort Peck hydro Unit 1	No
		Salt Lake City	Instability at Fort Peck hydro Unit 1	No

Table 2 illustrates that the most feasible options are 500 kV transmission lines that route from the generator location directly to the load center. In each Project, a 500 kV line to Spokane met criteria when generator output was scheduled to the same location. Some existing transformer taps may need to be adjusted to correct slight overvoltages. It is assumed that Category B violations detailed in the individual Project reports would be mitigated during project development.

The 500 kV line to Denver with schedule to Denver met criteria in all Projects except for Project 2 where a contingency caused instability at the Fort Peck hydro unit. In Project 4 the line to Denver produced an overload of 0.1% on the Bonanza-Mona 345 kV line. Verification of the Bonanza-Mona line rating would be required if this transmission alternative were to be considered further.

The six dispersed wind farms of Project 5 did not meet stability criteria with no new transmission lines added to the system. The 161 kV Hiline cannot support the transfer of additional generation. Further investigation showed that the new Blackfeet wind farm was unstable for contingencies as remote as Great Falls. Project 5 could be made functional by reducing the size of wind generation at Fort Peck and Blackfeet, and by installing reactive power support on several buses. However, increased system losses and additional stress on existing transfers limit the feasibility of Project 5. As suggested by the 500 kV Hiline upgrade of Project 4, proper transmission line upgrades of the Hiline would provide sufficient capacity for a 100 MW wind farm at Fort Peck. Similar transmission improvements in the Blackfeet area would be necessary to support 100 MW of new generation at Blackfeet. These results suggest that a 100 MW wind installation may be feasible at the other sites, but further detailed analysis of each site is necessary.

A typical pattern between similar transmission lines was observed in the power loss tables. The change in real power losses was relatively consistent between Projects with similar line routes, with the deciding factor being the location of the Project generator with respect to the scheduled load. Table 3 summarizes the system losses of the viable transmission line options that were identified in Table 2.

Table 3 - Change in Total System Losses for Viable Options

Line, Schedule	Net Losses (MW)	Percent of Generation
Project 1, 1000 MW near Colstrip		
L2, Spokane	114	11.4%
L3, Denver	42	4.2%
Project 2, 1000 MW near Great Falls		
L1, Spokane	83	8.3%
L3, Salt Lake City	-41	-4.1%
Project 3, 500 MW near Billings		
L1, Spokane	42	8.4%
L2, Denver	-41	-8.2%
L3, Salt Lake City	-65	-13.0%
Project 4, 600 MW near Fort Peck		
L1, Spokane	55	9.2%
L2, Denver	-27	-4.5%

The viable transmission alternatives with the most significant advantage in terms of losses are routed to Salt Lake City. As can be seen from Table 3, a decrease in total system losses was achieved for four of the transmission alternatives, with the greatest decrease occurring in Project 3 with line and schedule to Salt Lake City. The largest increase in total real power losses occurred for Project 1 with line and schedule to Spokane.

Some common Category A rating violations surfaced in the Projects. Table 4 summarizes these violations. All of the violations displayed in the table occurred when the Project line was not directly routed to Salt Lake City, but with the power scheduled to Salt Lake City over the existing system.

Table 4 - Common Rating Violations for Schedules to Salt Lake City

Line or Transformer Section	Rating (MVA)	Percent Loading by Project/Line. Schedule to Salt Lake City						
		P1 / L3	P2 / L2	P3 / L1	P3 / L2	P4 / L1	P4 / L2	P5 / (N/A)
Jefferson 161 kV Phase-shift xfmr	100	114%	119%	112%	-	116%	-	118%
Fish Creek-Goshen 161 kV	148	-	-	109%	102%	110%	104%	108%
Fish Creek-Grace 161 kV	148	-	-	106%	-	108%	101%	-
Bonanza-Mona 345 kV	650	121%	118%	-	113%	101%	120%	-

Table 4 also illustrates the presence of an existing constraint that limits flows between Utah and Colorado. The Bonanza-Mona 345 kV line incurs Category A rating overloads due to the heavy transfers from the PSCOLORADO area to the PACE area that result from scheduling the Project output to Salt Lake City with the transmission line terminating in Denver. Consequently, when the Bonanza-Mona 345 kV line becomes a contingency, the remaining 138 kV system in the vicinity of Bonanza experiences severe overloads and low voltage levels. These results suggest that the proposed transmission alternative would provide minimal new transfer capability into the Salt Lake City area.

Other patterns emerged between individual Projects for Category B contingency analysis. Rating and undervoltage violations prominent at Bell Substation suggest that the existing transmission in the area is critically loaded when Project lines are built to Spokane. Additions and improvements may be required to mitigate the injection point impacts, such as: line and transformer upgrades to Bell and Beacon substations, additional 230 kV lines from Bell South to Hatwai, extension of the 500 kV line south to Hatwai, or further southwest to Hanford. The Bonneville Power Administration (BPA) is presently conducting an extensive expansion study of the area to address many of these issues. Included in the BPA study is a new 500 kV transmission line from Bell Substation west to Grand Coulee which will complete a new “loop" of 500 kV sections in this area.

In the Projects with lines to Denver, Daniels Park Substation and the surrounding 230 kV PSCOLORADO system exhibits similar overloads to the Bell Substation. The 230 kV lines from Daniels Park to Waterton and Smokey Hill consistently experience overloads during nearby contingencies.

In both the Spokane and Denver schedules, additional transmission outlets are indicated because of the number of violations focused at the delivery points; however, these additions are beyond the scope of this study. It is assumed that these violations will be corrected as part of the project development and study process.

The 500 kV line route from Lethbridge to Salt Lake City varied slightly between Projects 1 and 2 in terms of facility connections at Townsend. The Townsend bus in the model represents a change in ownership point on the existing 500 kV corridor and is not an actual substation location; the new 500 kV line in Project 1 crossed but did not tie to the existing 500 kV system. In Project 2, the addition of a new switchyard at Townsend was estimated, and the effect of tying the two 500 kV systems was investigated.

With the switchyard in place at Townsend, improved power flow allocation was achieved, resulting in decreased system losses. Different Category B results were also observed. Isolation of the 500 kV systems in Project 1 generally resulted in Category B overloads and non-converged contingencies on the existing 500 kV lines from Colstrip to Taft as a result of heavy loading on the existing 500 kV circuits and relatively light loading on the new Project line. Joining the lines at Townsend alleviated this problem, but increased the severity of Category B overloads on the Anaconda-Dillon-Jefferson-Goshen 161 kV line for loss of the new 500 kV line.

A comparison of the Project 1 and Project 2 schedules to Lethbridge suggest that there is a transfer threshold at which the Great Falls-Lethbridge 500 kV transmission line becomes a critical contingency. Dynamic analysis in Project 2 investigated the transient effect of a fault with subsequent clearing of the new Great Falls-Lethbridge 500 kV line. The simulated loss of this line caused the tie branch between British Columbia and Alberta to open on low voltage. Subsequent response of the Alberta system was a prolonged dip in frequency to 58.6 Hz. Revisiting this same fault scenario in Project 1 scheduled to Lethbridge revealed no separation of the B.C. and Alberta systems, and consequently transiently stable conditions.

The primary difference between the two Projects is the magnitude of power transfer on the new tie line. Pre-fault power flows to Lethbridge along the Project 1 Great Falls-Lethbridge 500 kV line are 269 MW. The same line in Project 2 carries an additional 302 MW (or 571 MW total) prior to the fault. The collapse of the Alberta system is due to the heavy dependence on imports along the new Great Falls-Lethbridge 500 kV tie in the Project 2 model.

One other consistent outcome of dynamic analysis was identified. The Fort Peck Unit 1 hydro generator demonstrated instability for several fault scenarios. Scenarios that were run on cases with either increased load flow through the Hiline or new lines tying Colstrip to Fort Peck at 230 kV commonly resulted in transient events exceeding criteria on the Fort Peck system. In contrast, the new Ft Peck – Great Falls 500 kV line in Project 4 significantly increased capacity in the area and eliminated dynamic stability problems at Fort Peck. Additional analysis may show that a double circuit 230 kV or a single circuit 345 kV line may provide enough capacity to meet criteria and integrate new generation into the area.

Cost estimates of all Projects are summarized in the following table.

Table 5 - Cost Estimate Summary

Line Code	Substation Cost (thousands)	Transmission Cost (thousands)	Total Cost (thousands)
Project 1			
L1	$54,507	$104,739	**$159,246**
L2	$66,447	$325,720	**$392,167**
L3	$81,898	$287,027	**$368,925**
L4	$148,204	$497,030	**$645,234**
Project 2			
L1	$60,213	$202,981	**$263,194**
L2	$115,147	$381,606	**$496,753**
L3	$137,373	$428,683	**$566,056**
Project 3			
L1	$86,905	$327,214	**$414,119**
L2	$59,869	$283,018	**$342,887**
L3	$72,009	$319,131	**$391,140**
Project 4			
L1	$118,783	$455,433	**$574,216**
L2	$103,919	$398,694	**$502,613**
Project 5	$23,524	$14,915	**$38,439**

5. CONCLUSIONS

The completion of the Montana Transmission Study has demonstrated some of the obstacles that may be faced by plans to enhance the transmission system. It has demonstrated that increased export capability for the state of Montana requires new high-capacity lines, reactive support at both the sending and receiving ends of the lines, and the mitigation of specific system constraints. A "point-to-point" transmission approach provides the most export capability to a specific area, but has limited flexibility to alter the schedule in response to fluctuating market needs. As such, careful evaluation of anticipated load centers would need to be conducted before planning any one transmission line route. New problems may arise in the receiving area that must also be considered.

It was also demonstrated throughout the results of the individual Project reports that new radial 500 kV lines alone do not provide sufficient capacity for new 1000 MW generation facilities in

Montana. If any section of the line experiences an outage, the existing system cannot meet the new transfer requirements. This is especially true in locations where there are no existing 500 kV facilities. A combination of possible solutions may be employed during the project development process:

- Mitigation of single contingency violations on existing lines.
- Special tripping schemes for the new generation when critical 500 kV line sections are lost.
- Additional line sections from the plant location to other points in the system to help reallocate power flow during contingencies.
- Upgrades or additions to transmission facilities at delivery points to alleviate overloading of existing transmission infrastructure.

The issues of accurate Colstrip ATR simulation will need to be addressed if additional consideration is given to a specific Project. The modeling data used for Fort Peck units may also need to be refined.

Appropriate interconnection requirements must be met, and studies performed for any projects that develop beyond the purely conceptual level of this Study. The rules and requirements for new projects are regulated by the WECC and the specific affected entities' own reliability criteria. These rules and requirements must be strictly adhered to by anyone wishing to attach to the western transmission grid system. The results of this Study do not complete any such requirements or replace the need for specific System Impact Studies or the Open Access Same-Time Information System (OASIS) request process.

6. REFERENCES

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